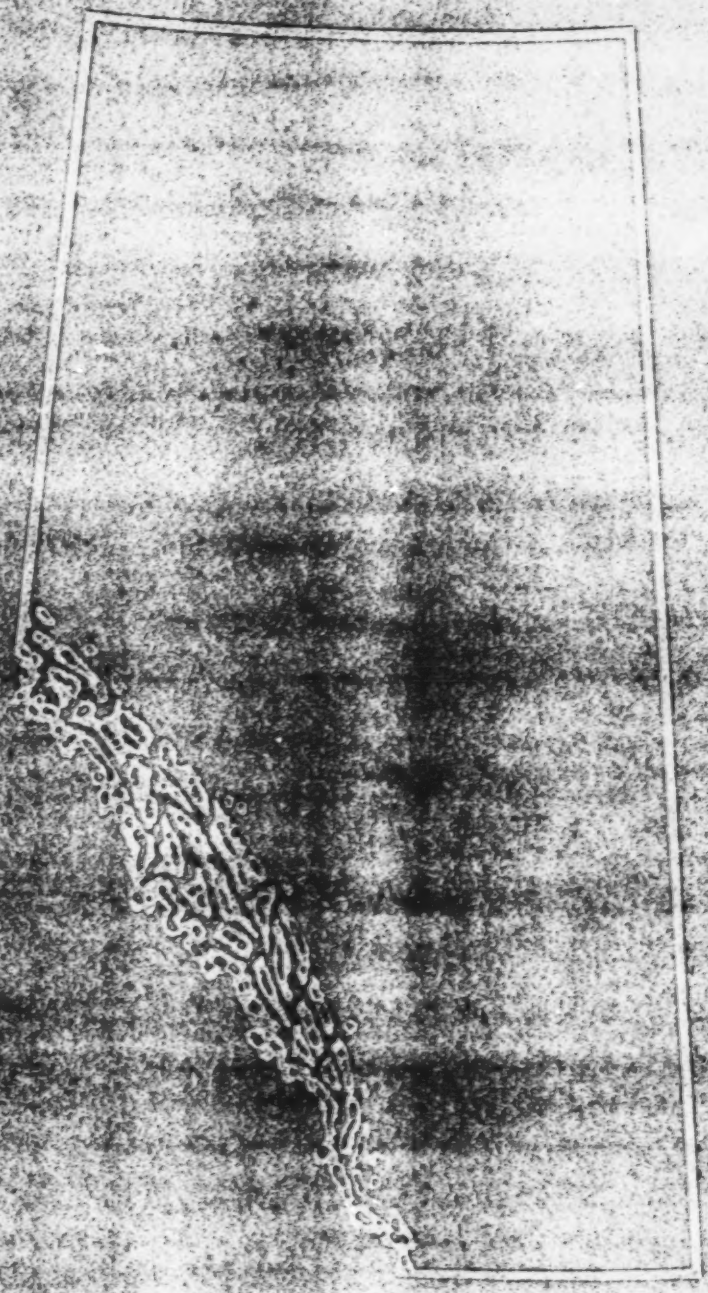

# Alberta PETROLEUM MARKETING COMMISSION

## 1990 ANNUAL REPORT

91-05801/

Alberta PETROLEUM MARKETING COMMISSION

1900 - 250 Sixth Avenue S.W., Calgary, Alberta, Canada T2P 3H7 Telephone (403) 297-5500 Fax (403) 263-8144

April 30, 1991

The Honorable Rick Orman
Minister of Energy
Government of Alberta
Legislature Building
Edmonton, Alberta
T5K 2B6

Dear Sir:

In accordance with the provisions of the Petroleum Marketing Act and the Take-or-pay Costs Sharing Act, the Alberta Petroleum Marketing Commission has prepared a general report summarizing its transactions and affairs for the fiscal year ended December 31, 1990. I have the pleasure to submit the 1990 Annual Report that you may lay a copy before the Legislative Assembly.

Respectfully,

D.A. Lucas
Chairman

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*Old Friend*, an original watercolor by Fanny Fynebuik, depicts the tranquility of a pumpjack set against the rugged Rocky Mountains.

Ms. Fynebuik, a graduate of the Dutch College of Arts and Crafts, was born in Holland and has resided in Calgary since 1957. An active member of the Calgary Sketch Club and the Federation of Canadian Artists, she has also studied at the Alberta College of Art and is the recipient of several awards.

# MESSAGE FROM THE CHAIRMAN

Extreme price uncertainty and volatility returned to world crude oil markets during the latter part of 1990. A very weak market in mid-year was jolted by political events in the Middle East. Prices were sufficiently strong during the latter part of the year to modify the rate of decline in Alberta light and medium crude oil production.

During the year, the logistics of a deregulated crude oil market continued to evolve. The APMC and other sellers pursued opportunities for market diversification within the United States and offshore. Changing competitive conditions and decisions by refiners in the Montreal market resulted in throughput on the Interprovincial Pipe Line Company Sarnia to Montreal line being eroded. By year end, deactivation of this line was a concern.

Notwithstanding the stronger second half prices, royalty volumes continued to decline during 1990 because of decreased conventional light and medium production in Alberta. Overall, revenues on sales of royalty barrels by the APMC increased significantly because of stronger prices.

On the natural gas side, both sales of Alberta natural gas and Alberta's share of Canadian exports increased, despite soft demand in some markets. Major progress was made towards diversifying market opportunities, with the Iroquois/Tennessee project to the United States Northeast approved and a major hearing into expansion of the TCPL system completed. While the outlook for gas demand is muted in the near term, the longer-term prospects continue to be favourable.

The APMC was extremely active in regulatory proceedings in Canada and the United States during 1990, with the focus on the timely and economic expansion of pipelines, pipeline tolling and access issues, and gas supply procurement arrangements. These issues will continue to require strong and effective representations by the APMC in the year ahead.

D.A. Lucas
Chairman
April 30, 1991

# MARKET OVERVIEW

## PETROLEUM MARKETS

In terms of world oil markets, the invasion of Kuwait by Iraq on August 2, 1990 essentially divided the year into two very different parts. Extreme volatility in oil prices marked the latter half with WTI soaring to US$41.15 in October, from a June low of US$15.06.

During the first quarter of 1990, North American crude oil prices stayed within a narrow range of US$21.00 to US$23.00, supported by unusually cold weather. In the second quarter, oil prices dropped because of persistent OPEC overproduction, a seasonal downturn in oil demand and an economic slowdown in industrialized countries. After bottoming out in June, prices began to recover because the approaching July OPEC meeting was expected to result in production cutbacks.

Oil markets were thrown into turmoil by the Iraqi invasion of Kuwait in August and the subsequent United Nations embargo on oil exports from both countries. The embargo immediately curtailed world oil supply by 4.0 million barrels per day. Oil prices rose to over US$40.00 by mid-October, a level not seen since 1981. The subsequent decline in prices over the fourth quarter was almost as spectacular. Rapid expansion in OPEC production, warm weather and stagnating world economies combined to fill the crisis-induced supply gap and eliminate the "war premium".

Due to strong prices during the latter half of the year, 1990 WTI prices averaged US$24.50, rising by US$4.91 or 25 percent from 1989. This was the second consecutive annual increase of more than 20 percent. The OPEC basket price gained similarly, averaging US$22.25 for the year. This exceeded the minimum reference price goal of US$21.00 set at the July OPEC conference.

OPEC production averaged 23.1 million barrels per day during 1990, up by 1.3 million barrels or six percent. This was the highest level of output in ten years, and it belied the loss of embargoed oil to world markets. With the embargo in place, other OPEC producers stepped in quickly, filling the entire supply gap by late November. Saudi Arabia was the main contributor of incremental volumes, accounting for 3.0 million barrels per day of additional supply.

Excluding Centrally Planned Economies (CPE), non-OPEC crude oil output increased marginally in 1990. CPE net exports fell from 1.9 million barrels per day in 1989 to 1.7 million barrels per day. Soviet oil production dropped from 12.0 million barrels per day in January to 10.9 million barrels per day in December, the lowest level in ten years. Total 1990 world production outside the CPE increased by 1.2 million barrels per day to reach 53.6 million barrels per day, an increase of two percent.

During 1990, total world oil consumption outside the CPE averaged 52.9 million barrels per day, compared to 52.3 million barrels per day for 1989. This reflected continued strong growth in consumption in several Pacific Rim countries. OECD oil consumption was virtually flat in 1990, due to higher prices and the recession.

Despite the turmoil of 1990, world oil markets were much more resilient than during the previous crises of 1973 and 1979. The availability of surplus OPEC capacity and IEA's readiness to release strategic reserves, if necessary, helped to settle the market. In addition, warmer weather and the recession helped to curtail demand. After the Gulf situation returns to normal, OPEC will be faced with revising oil production quotas in order to accommodate Iraqi and Kuwaiti production.

A number of analysts have observed that the Gulf crisis could result in long-lasting consequences for oil markets and energy policies. These include: (1) renewed interest in exploration and production in OECD countries; (2) renewed emphasis on energy security and diversification of energy sources; and (3) reduced reliance on OPEC oil.

## United States

During 1990, United States domestic crude oil production dropped for the fifth consecutive year. Although less than the record 525 thousand barrels per day decline of 1989, output fell by a significant 390 thousand barrels per day (five percent) to 7.3 million barrels per day. This was the lowest level since 1961. Annual production has declined by 1.7 million barrels per day (20 percent) since 1985.

After rising by more than 60 percent between 1985 and 1989, crude oil imports were flat during 1990, at 5.9 million barrels per day. Product imports declined by 145 thousand barrels per day in 1990, because of the recession and higher product prices. Overall, total imports remained at 8.0 million barrels per day, representing 47 percent of total domestic deliveries.

Total United States petroleum deliveries declined in 1990 for the first time since 1983. Total domestic product deliveries during the year dropped by 365 thousand barrels per day to 17.0 million barrels per day. Gasoline, distillate and residual fuel oils each declined by about 125 thousand barrels per day, while kerosene jet fuel deliveries increased slightly.

## Canada

Canadian production of crude oil and equivalent averaged 1.64 million barrels per day in 1990, a decrease of 19 thousand barrels per day from 1989. Alberta production averaged 1.37 million barrels per day for the year, a decline of 19 thousand barrels per day, or one percent (Figure 1). Although Alberta production was affected by dwindling conventional light and medium crude reserves, higher crude oil prices helped slow the rate of decline compared to the previous two years.

Overall, 1990 sales of Alberta crude fell by two percent, to 1.37 million barrels per day. Domestic deliveries fell by 38 thousand barrels per day, reflecting unscheduled refinery turnarounds and sluggish demand (Figure 2). Exports to the United States markets increased by 11 thousand barrels per day, while offshore exports were unchanged.

Canadian deliveries to Ontario decreased by 31 thousand barrels per day in 1990. However, Ontario remained the largest Canadian market for Alberta crude, accounting for about 42 percent of sales. Across the border, slightly increased deliveries to the United States Midwest and Montana markets were partially offset by lower deliveries to the West and East Coast markets. The Midwest remained the primary export market for Alberta crude, accounting for three-quarters of all exports.

**FIGURE 1**
ALBERTA CRUDE OIL PRODUCTION
THOUSAND BARRRELS PER DAY

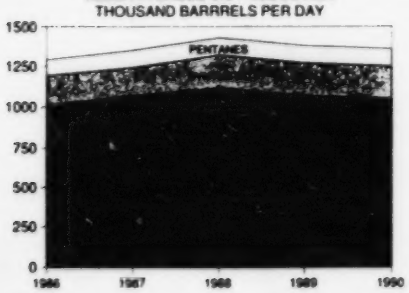
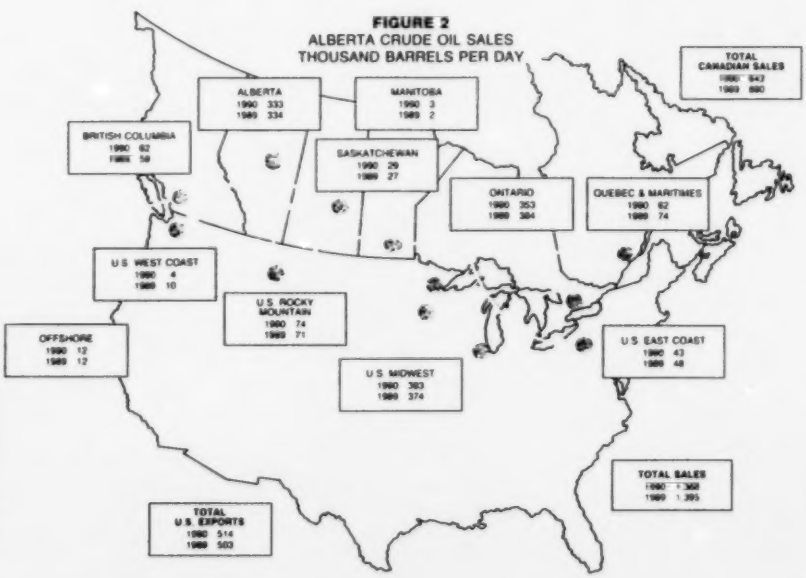



**FIGURE 2**
ALBERTA CRUDE OIL SALES
THOUSAND BARRELS PER DAY



While refinery receipts of domestic crude oil fell marginally in 1990, total feedstock receipts increased by 49 thousand barrels per day (three percent), reflecting higher crude oil imports. Canadian refiners used most of these incremental feedstocks to maximize throughput during the Gulf crisis. As a result, 1990 refinery runs increased by 33 thousand barrels per day (two percent) for the year to 1.66 million barrels per day. Meanwhile, domestic sales of petroleum products fell two percent to 1.45 million barrels per day.

Sluggish demand reflected the effects of the recession and higher oil prices during the second half of the year. Lower end-user consumption and higher refinery receipts and runs translated into higher year-end stocks of crude oil and products. Crude stocks grew by 2.2 million barrels (13 percent), while total product stocks also gained 2.2 million barrels (three percent).

Overall, 1990 was a very eventful year, with mixed consequences for the Canadian oil industry. The Gulf crisis boosted oil prices, generated higher cash flows for Canadian producers and slowed the decline in Canadian crude oil production. However, these events were accompanied by considerable price uncertainty and recessionary pressures on domestic petroleum consumption.

## NATURAL GAS MARKETS

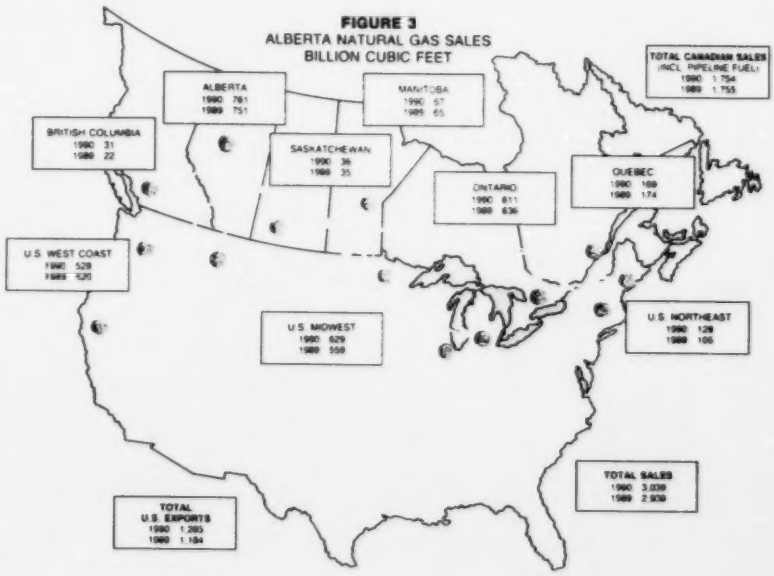
Generally encouraging signs were presented to the natural gas industry during 1990. Approval of the Iroquois/Tennessee pipeline project to the United States Northeast and TCPL's proposed expansion were major steps towards the diversification of Alberta producers' traditional markets. Alberta gas sales increased by three percent in 1990, largely because of growth in exports. In addition, the average Alberta border price increased for the first time since deregulation.

### Canada

Total domestic end-use consumption of natural gas fell by four percent during 1990 to 1.9 trillion cubic feet. While gas demand grew because of increased competitiveness in Quebec, this was offset by the recession and warmer-than-normal temperatures in other gas-consuming regions of Canada. As well, a return to normal water levels in British Columbia reduced gas usage in utility electrical generation in that province.

Total domestic sales of Alberta natural gas (Figure 3) remained unchanged at 1.8 trillion cubic feet. Reduced sales to Central Canada were offset largely by increased sales to the Western Provinces. While the proportion of interprovincial sales made under direct arrangements increased to 39 percent compared to 30 percent a year ago (Figure 4), gas utilities in Central Canada also increased the volume of direct sales secured under longer-term contracts (Figure 5). Since longer-term direct sales tend to be higher-priced, the average Alberta border price of gas sold in the domestic market increased slightly over 1989. This was the first nominal year-on-year price increase since the gas industry was deregulated.

**FIGURE 3**
ALBERTA NATURAL GAS SALES
BILLION CUBIC FEET



United States

United States natural gas demand dropped by two percent in 1990, to 18.8 trillion cubic feet. Unusually warm weather resulted in high storage levels. In addition, weather-related declines in residential and commercial demand offset industrial sector growth caused by competitive prices and environmental considerations.

The average natural gas spot price was US$1.58 per thousand cubic feet during the year, unchanged from 1989. Strength in the first and fourth quarters significantly offset weak second and third quarter prices. Extremely cold temperatures helped support prices in the first quarter. Fourth quarter strength, in part, reflected producers' ability to shut-in gas and hold out for higher prices, while buffered by increased cash flows generated by higher oil prices.

Natural gas futures started trading on the NYMEX in 1990. A total of 132 thousand contracts traded during the year at an average price of US$1.78 per thousand cubic feet. Trading exceeded that seen in the first year of the NYMEX crude oil contract in 1983. Total volumes for gas were equivalent to approximately eight percent of North American consumption. By comparison, during the first year of trading for NYMEX crude, volumes equated to only six percent of consumption. Trading on the natural gas NYMEX is anticipated to increase over the next few years as buyers and sellers seek cost and revenue certainty.

Canadian exports of natural gas continued to increase in 1990, up by seven percent to 1.4 trillion cubic feet. Exports reached eight percent of United States demand, with the majority of the growth in short-term sales into the Midwest. Alberta's share of Canadian exports was 1.3 trillion cubic feet or 90 percent. This volume represents an eight percent increase over the Province's 1989 exports.

Events in the United States focused on the many pipeline proposals advanced to provide additional capacity to serve the market, particularly the Northeast and California. Canadian and United States producers clearly want to increase their access to markets and diversify their sales. The Federal Energy Regulatory Commission's new policy of approving Optional Certificate (OC) applications conditional on the successful completion of both the open season for capacity allocation and environmental review has streamlined the regulatory process and is viewed as a positive step towards freeing market forces.

In the Northeast, the Iroquois/Tennessee pipeline project overcame many regulatory hurdles to allow construction to begin early in 1991. Other pipeline expansion proposals relevant to Canadian gas included the revised Northern Border expansion/extension proposal in the Midwest and the Northwest Pipeline Corporation planned expansion into both the California and Pacific Northwest markets. Among the pipeline proposals to serve the growing Southern California market, the Kern River Gas Transmission Corporation, Altamont Gas Transportation Company and the Pacific Gas Transmission Company/Pacific Gas and Electric Company expansions received regulatory approvals conditional on environmental screenings. Together with the pending El Paso Natural Gas Company and Transwestern Pipeline Company expansion proposals to transport additional San Juan coal seam gas, these would result in significant incremental capacity into the California market, relative to anticipated growth in demand. High levels of take due to the dewaterization process for coal seam gas could cause lower takes from traditional suppliers to the California market.

**FIGURE 4**
ALBERTA INTERPROVINCIAL NATURAL GAS SALES

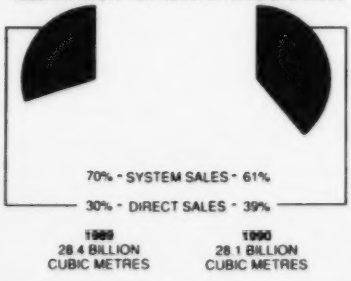
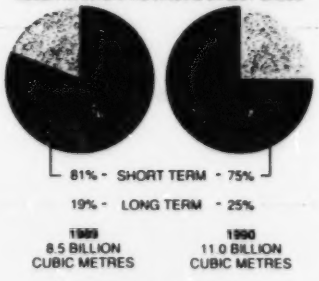



**FIGURE 5**
ALBERTA INTERPROVINCIAL DIRECT SALES



Given the renewed interest in the environment and secure supply following the Gulf crisis, the outlook for North American natural gas demand in the 1990's is reasonably good. However, recession and a continuation of unusually warm weather could dampen gas demand in the near term. Furthermore, Alberta producers continue to face stiff competition from other suppliers in both traditional and new markets.

Additional pipeline capacity into economic markets is required for Alberta producers to be able to share in demand growth. The price of this access, in the form of the tolls producers pay on pipeline systems, will be key in terms of their decisions to commit to particular markets. These issues will necessitate a continued and effective representation by the APMC at the regulatory level, to ensure that expansions are implemented in a timely way and that Alberta producers continue to benefit from fair and non-discriminatory access to pipeline service.

## OVERVIEW OF OPERATIONS

The APMC, as agent for the Alberta Crown, is responsible for gathering and marketing crude oil taken as royalty-in-kind from Crown leases in the Province. The Commission also markets Alberta's 16.74% equity share of synthetic oil from the Syncrude Canada Ltd. project, and offers contract marketing services to Alberta producers.

As the largest volume seller of crude oil in Canada, the APMC manages a diversified sales portfolio, supplying crude to a wide base of refiners throughout Canada and the northern tier of the United States. It also maintains a high profile within the Province, gathering crude oil at more than one thousand receipt points for feeder pipeline transport to local refineries or injection into ex-Alberta pipeline systems.

The APMC draws from its direct involvement in the marketing and transportation of crude oil to keep the Alberta Government advised of ongoing industry developments and market trends. It also participates on several industry task forces and committees to promote an efficient operating environment, which benefits the long term interests of the industry and the Province.

## SALES

1990 began on a positive note for Canadian producers. Strong demand for light sweet crude oil in the United States resulted from a weather-related surge in demand for heating oil and the need to build gasoline inventories in advance of the summer driving season. Production problems at the Syncrude Canada facility in December 1989 reduced supplies of light sweet crude in January and early February.

A first quarter frenzy of offshore purchases and the rather quick replenishment of United States gasoline inventories served to dampen second quarter demand. OPEC's continued overproduction and the abundance of foreign and domestic barrels at the Gulf Coast and in the Midcontinent doused the first quarter's bullish spark in the United States oil market. OPEC oversupply and the growing global surplus of crude depressed prices through the spring and early summer months. Weak market fundamentals prevailed and crude for immediate delivery traded at a discount to future months.

High inventory levels and refinery capacity utilization sent NYMEX prices on a downward spiral, reaching a low of US$15.06 on the final day of trading for July delivery (Figure 7). The Canadian crude market was over-supplied as demand declined due to sluggish product requirements in North America. An abundance of crude began to bottleneck in IPL, forcing shippers to search for alternate markets.

The Iraqi invasion of Kuwait on August 2 jolted crude oil markets. Despite the surplus of crude, feared shortages pushed the price of WTI to an all time high of US$41.15 for November delivery. The concern over loss of Iraqi and Kuwaiti production abated somewhat with the restoration of OPEC production to pre-invasion levels. Despite the extreme price volatility in the last quarter, high prices prevailed to benefit Canadian producers.

Receipts of light and medium royalty oil totalled 7.3 million cubic metres (46.0 million barrels), down four percent from 1989 owing to decreases in provincial production. Royalty receipts of heavy crude were 917 thousand cubic metres (5.8 million barrels), up seven percent from 1989. The crisis in the Gulf pushed total revenue from royalty sales of conventional crude production to $1.3 billion, up 26 percent from the previous year. Figures 8 and 9 summarize the total provincial production of conventional crude oil and the royalty share which is marketed by the APMC.

**FIGURE 6**
1990 PRICE PREMIUMS WTI vs. BRENT
U.S. DOLLARS PER BARREL

**FIGURE 7**
NYMEX 1990 WTI SPOT MONTH
AVERAGE SETTLEMENT PRICES
U.S. DOLLARS PER BARREL

Table 1 shows the monthly reference prices for sweet and sour crude paid by the APMC for field purchases during 1990. APMC reference prices are based on sales revenue net of transportation costs from Edmonton to final point of sale. Quality adjustments and pipeline tariffs are deducted from APMC reference prices to determine field prices for more than six thousand producing battery locations.

### Montreal Market Lost

The availability of relatively inexpensive offshore crudes during the first half of 1990 reduced the competitiveness of Canadian crudes in the Montreal market. Montreal refiners, anticipating a continuation of this situation, stepped up purchases of offshore crudes, cutting back Canadian supplies. This pushed more Canadian production into the already saturated United States markets. Light sour crudes suffered the largest price impact as sweet/sour differentials spread to unprecedented levels.

With throughput on the Sarnia to Montreal pipeline eroding, deactivation of the line became a major concern by year end. The ramifications of this issue have yet to be resolved.

### New Markets Explored

Weakness in conventional markets encouraged the APMC and other Alberta producers to pursue opportunities in non-traditional markets. Increasing volumes of light sweet Canadian crude were moved to the Fort Laramie-Guernsey area of Wyoming. Prospects for regular deliveries to the Rocky Mountain area appear to be improving as local supply continues to decline and requirements for Canadian imports grow.

With high levels of apportionment on IPL (eight percent in October and November, and seven percent in December) and weak demand for crude at Edmonton, provincial producers looked to the Pacific Rim and the Puget Sound markets as alternatives. Weak West Coast product demand and a surplus of Alaska North Slope crude reduced the desirability of the Puget Sound market. The APMC was ultimately successful in arranging the sale of a cargo of Alberta crude to Taiwan and will continue to pursue market diversification opportunities in the Pacific Rim and the United States West Coast.

**TABLE 1**
1990
CRUDE OIL REFERENCE PRICES
(DOLLARS PER CUBIC METRE)

| | SWEET CRUDE | SOUR CRUDE |
|---|---|---|
| JAN | 156.51 | 152.10 |
| FEB | 161.46 | 155.46 |
| MAR | 152.73 | 143.57 |
| APR | 140.52 | 129.51 |
| MAY | 133.41 | 122.71 |
| JUN | 125.32 | 114.80 |
| JUL | 123.57 | 114.28 |
| AUG | 166.43 | 157.86 |
| SEP | 217.42 | 212.62 |
| OCT | 254.87 | 245.02 |
| NOV | 240.01 | 227.07 |
| DEC | 207.43 | 192.39 |
| AVG. | 173.31 | 163.95 |

Prices shown are for crude oil with a density of 825 kilograms per cubic metre and a sulphur content of not more than 5 grams per kilogram delivered into, respectively, sweet or sour pipelines.

**FIGURE 8**
ALBERTA CONVENTIONAL CRUDE OIL PRODUCTION
MILLION CUBIC METRES

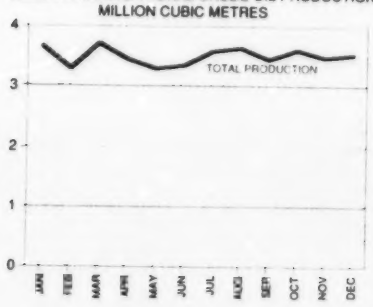
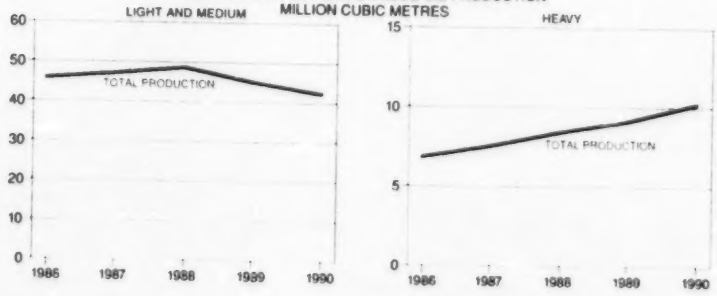



**FIGURE 9**
ALBERTA CONVENTIONAL CRUDE OIL PRODUCTION
MILLION CUBIC METRES



## NATURAL GAS MARKETING ACT

### Services Relating to Price Components

Under the authority of Part 1 of the Act, the APMC may agree to provide the following services under a gas contract:

- the determination, confirmation, or verification of price components;
- the allocation of all or part of the amount of a price component to a gas contract;
- the redetermination or the calculation of adjustments of price components;
- the implementation of other services that pertain to price components.

During 1990, the APMC provided price component services to three clients on a cost recovery basis.

### Producer Support for Downstream Pricing

Part 2 of the Act provides for producer input to the resale price if producers and buyers have agreed to a netback pricing clause in their natural gas purchase contract. Regulations require the buyer to obtain support from producers representing a minimum of 51% by number and 60% by volume of supply.

Procedurally, a buyer presents a resale proposal to the producers for voting purposes and the results of the vote are provided to the APMC. A finding of producer support is issued if the legislated criteria are met. Shippers of netback gas may be subject to penalties imposed by the APMC if gas is shipped without a finding of producer support. During 1990, the APMC issued 66 decisions in respect of producer support.

### Information Collection

The APMC collects information relevant to the purchase and sale of marketable Alberta natural gas under Part 4 of the Act. The data collected include field purchase information provided primarily by first buyers, while figures relevant to consumption within Alberta are supplied by large volume end-users and designated distributors. Ex-Alberta sales information is provided by the owners of the natural gas at the time it leaves Alberta. Owners similarly provide information pertinent to imports of natural gas into Alberta.

Information is collected on a confidential basis for use in developing government policies, verifying royalty payments, and establishing the average market price (AMP) used in determination of the royalty share of natural gas production. The statistics are also used to monitor progress under the October 31, 1985 Agreement on Natural Gas Markets and Prices.

## TAKE-OR-PAY COSTS SHARING ACT

The National Energy Board (NEB), under the terms of the October 1985 Agreement, was requested to review the availability of transportation service on the TCPL system, taking into account the equitable sharing of take-or-pay charges. In its May 1986 report, the NEB recommended that take-or-pay costs be shared by Alberta non-system gas transported on the TCPL system, and that the arrangements be administered by the Government of Alberta.

In response, the Government of Alberta enacted the Take-or-pay Costs Sharing Act which became effective November 1, 1986. This Act provides for the sharing of take-or-pay financing costs of Consolidated Natural Gas Limited and TCPL by way of a monthly levy on users of the TCPL system whose shipping arrangements were entered into after October 31, 1985. The levy on users of the system was set at ten cents per gigajoule for the period November 1, 1986 to October 31, 1989. As of November 1, 1989, it was reduced to seven cents per gigajoule.

The APMC makes monthly determinations of levies to be applied to TCPL producers, Consolidated producers, shippers on the NOVA system, shippers on other provincial carrier systems, and to provincial carriers that own the gas. The APMC also determines, on a monthly basis, the quantities of natural gas exempted from the levies. Revenues derived from the assessment of levies are deposited in the Take-or-pay Costs Sharing Fund for subsequent payment of take-or-pay financing costs. Levies assessed against parties, excluding TCPL and Consolidated producers, accounted for 22.5 percent of total levies during 1990.

## NATURAL GAS PRICING AGREEMENT ACT

Under provisions of the Natural Gas Pricing Agreement Act, the APMC has authority to redetermine the Alberta Cost of Service for an original buyer for any month up to and including October 1986 in order to comply with decisions of the Alberta Public Utilities Board. During 1990, the APMC finalized one such decision relating to determinations of Alberta Cost of Service, and another was outstanding as a result of an appeal to the Alberta Public Utilities Board.

In its role as an advocate for the Province of Alberta on regulatory matters, the APMC took a high profile in proceedings before the National Energy Board (NEB) in Canada and, in the United States, the Federal Energy Regulatory Commission (FERC) and the California Public Utilities Commission (CPUC). During the year, the regulatory arena in Canada and the United States was dominated by three issues: (1) pipeline expansions and new pipeline projects; (2) appropriate tolling methods for transportation systems; and (3) access to transportation systems and gas supply procurement issues.

The ability to attach new markets and to increase market share in traditional ones is a significant concern for Alberta producers. To this end, the APMC was involved in many regulatory proceedings with respect to pipeline expansion and new pipeline construction. In general, the APMC supported expanding transportation systems from Alberta into economic markets. Projects to serve the United States Northeast and California dominated the agenda during 1990.

In the Northeast, the 370-mile Iroquois/Tennessee pipeline project was prominent. In November, the FERC approved construction of this pipeline, which cleared the way for a major expansion of the TCPL system. This will be the first major expansion of Canada's mainline gas transportation system in a decade. The expansion will give Alberta producers access to markets in New York, New Jersey and New England, as well as the opportunity for expanded sales into domestic markets.

The favourable decision on Iroquois/Tennessee from the FERC culminated a lengthy proceeding. The most contentious issues related to market need and differences in pipeline rate design between Canada and the United States. Project opponents claimed that Iroquois/Tennessee had an unfair advantage by virtue of these differences, and that the Iroquois/Tennessee demand projections were too optimistic. The FERC rejected these arguments in its decision. The APMC participated in this proceeding to support the pipeline project.

On the United States West Coast, the CPUC continued to consider the supply and availability of interstate gas pipeline capacity into California. In its Final Decision released in February 1990, the CPUC decided that competitive forces, rather than a CPUC-endorsed project ranking, should determine which project(s) would serve California. The APMC had advocated this position on the grounds that regulatory agencies should not dictate or pre-determine choices in a competitive, deregulated market.

In December 1990, the CPUC conditionally approved an expansion of the Pacific Gas and Electric Company (PG&E) system and certified the final environmental impact report. This project, in conjunction with an expansion of the Pacific Gas Transmission Company (PGT) system, would bring an additional 755 million cubic feet per day of Canadian gas primarily to Southern California. Two other expansion projects also are vying for the California market -- Altamont Gas Transportation Company and Transwestern Pipeline Company. These projects represent an additional 1,795 million cubic feet per day of capacity to serve the California market from Canada.

Tolling and rate design issues were particularly prominent on the regulatory agenda during 1990. The APMC was involved in proceedings in Canada and the United States to ensure that Alberta producers benefit from equitable tolls and terms of access to pipelines, as well as to monitor competitive developments affecting Alberta gas markets.

Dominating the year was an application by TCPL to the NEB for a $2.6 billion expansion to its transportation system to serve domestic and export markets. The hearing on this issue was protracted due to the size of the application, the composition of the market requirements underpinning it and the potential impact on tolls. The appropriate method for charging tolls on the expanded pipeline system and the method for determining the economic feasibility of the proposed facilities were particularly contentious issues.

The APMC participated very actively in this hearing because the orderly expansion of the TCPL system is viewed as a critical element in moving to a market-based gas pricing regime. Based on reasons of equity and fairness, the APMC presented witnesses advocating that rolled-in tolling continue to be applied to the expanded TCPL system. In addition, the APMC developed and proposed to the NEB a market-based test of economic feasibility to ensure that uneconomic expansions do not proceed. The NEB agreed with the arguments supporting a continuation of rolled-in tolls. A decision has not yet been issued regarding certification of the proposed facilities.

During 1990, the APMC also was active on a Task Force established to negotiate the settlement of various issues associated with TCPL's 1991 tolls application.

In the United States, the APMC monitored closely and participated where necessary in the rates proceedings of various United States pipelines. The APMC's objective was to ensure that the adopted rate design was fair and equitable to all shippers on the pipeline systems.

During 1990, several developments took place with respect to Northern Natural Gas Company's 1988 tariff filings. Northern Natural's original application was very contentious because it sought to modify its rate design for certain classes of service, increase its cost of service and review the terms and conditions of its service. From Alberta's perspective, the most important issue was the proposed continuation of postage stamp rates for interruptible transportation in Northern Natural's market zone. Together with the Canadian Petroleum Association (CPA), the APMC opposed the continued zoned postage stamp rate because it discriminates against short-haul Canadian gas in favour of long-haul United States gas. The APMC and CPA favoured the adoption of mileage-based rates.

The importance of this issue to the Alberta producing community was larger than just Northern Natural's application, however. Other United States pipelines also use the postage stamp rate and the FERC Policy Statement on Rate Design of 1989 has increased the focus on rate design issues. As a result of these broader considerations, the APMC and CPA advocated that a complete record be established in the proceeding and did not support any settlement that did not deal with the postage stamp issue. In addition, the APMC and CPA filed evidence outlining specific mileage-based rates.

After several months of settlement negotiations, a compromise was struck which would result in lower tolls for Canadian gas moving through Northern Natural's market zone. However, the rate design issue itself was unresolved, and likely will be argued again. Northern Natural must present a new tariff filing to the FERC in 1991.

In January 1990, the FERC applied Opinion 256 to PGT. This order disallows the full pass-through of Canadian demand charges to United States pipelines buying gas for resale, and instead requires that a portion of these costs be passed through in the commodity rate. In addition to applying Opinion 256, the FERC moved PGT from a full fixed-variable to a modified fixed-variable rate design. This shifts a portion of PGT's return on equity and related taxes from the demand component to the commodity component of its price to PG&E. The net effect of both decisions is to increase the commodity price of gas delivered by PGT to PG&E by some US$0.17 per thousand cubic feet. This has implications for the competitiveness of Canadian gas vis-a-vis Southwest gas supply in the California market. The APMC had argued extensively for retaining the full fixed-variable rate design and for the "as billed" pass-through of Canadian demand charges.

During 1990, Great Lakes Gas Transmission Company also proposed changes in its gas tariff. The APMC and CPA jointly participated in the settlement conferences and subsequent hearing. While the settlement conferences resolved many cost-of-service matters, three issues went to litigation: (1) the incremental versus rolled-in tolling methodology to be applied to new facilities on Great Lakes; (2) the replacement of the modified fixed-variable rate design on Great Lakes with a full fixed-variable rate design; and (3) the appropriate tolling method for interruptible and authorized overrun rates.

The APMC and CPA supported TCPL in the litigation proceedings and submitted final argument in support of Alberta's interest.

During 1990, the APMC also participated in toll design and procedural matters with respect to crude oil pipelines. At a 1989 hearing before the NEB, the APMC opposed a tolling methodology proposed by IPL to recover the costs of constructing special facilities that would benefit only certain users or classes of users. At that time, the APMC argued that these costs should be segregated and charged only to the actual users of the facilities, consistent with the principles of cost causality and user-pay. The NEB held that IPL's proposed methodology did not violate these principles, but rather incorporated them in a "different fashion".

The importance of these developments was highlighted later in 1990 when IPL applied to the NEB for approval to construct a natural gas liquids storage facility at Edmonton. IPL proposed a toll structure whereby part of the cost of this special facility would be paid for by the general system users. The APMC argued against this proposal on the grounds that it violated the principle of user-pay.

The NEB has not yet issued its decision with respect to the facilities and tolling issues.

The APMC devoted significant resources in 1990 to addressing pipeline access and gas supply procurement issues, particularly in the United States.

Together with the CPA, the APMC was active in Great Lakes' open access filing at the FERC. This filing addressed the priority of interruptible service to be given to established shippers, the allocation of capacity and the availability of contract overrun service. The APMC and CPA encouraged the FERC to implement a lottery system to award available interruptible capacity rather than to assign priority rights. To preclude a secondary market developing for capacity, the APMC and CPA also proposed that parties in the queue be required to use their capacity or forfeit their positions.

In February 1990, the CPUC issued an Order Instituting Rulemaking (OIR), which established new gas utility procurement rules in California. The APMC actively participated in subsequent developments and decisions.

Specifically, the APMC advised the CPUC as to the jurisdictional, operational and regulatory implications of the OIR upstream of California. The key concern to Alberta was that the long-standing contractual arrangements in place between Alberta producers and California customers not be undermined by regulatory intervention. In addition, the APMC was concerned that the competitiveness of Canadian gas supply in the California market be represented properly.

In addition to participating at the procedural level, the APMC also engaged in settlement discussions with a diverse group of California parties, and in consultation with Alberta producers. These discussions resulted in the Access Agreement, which was filed in September with the CPUC. This agreement would give PG&E's non-core customers direct access to a specified volume of gas to be supplied by producers in the Alberta and Southern Gas Co. Ltd. pool. In November, a substantial majority of Alberta and Southern producers supported the Access Agreement in a vote conducted by the APMC. The Access Agreement

ensures an orderly development of supply arrangements from Alberta as the CPUC continues with its restructuring initiatives.
In October, the CPUC resumed activity on its capacity brokering proceeding, which had been suspended pending resolution of the gas supply procurement OIR. Capacity brokering workshops, at which the APMC participated, were held late in 1990. The APMC also submitted comprehensive capacity brokering evidence to the proceeding scheduled for early 1991. Similar interventions before the FERC likely will be necessary over the coming year.

Early in 1990, the NEB reviewed certain aspects of the Market Based Procedure. The focus was the NEB's use of social cost benefit analysis for determining the public interest associated with proposed gas exports. The APMC filed comments encouraging the NEB to discontinue the use of social cost benefit analysis since it is inconsistent with a deregulated market. Instead, the APMC recommended that the NEB determine the public interest on the basis of market-related criteria. The NEB subsequently discontinued using social cost benefit analysis in assessing export licence applications, as well as in considering Part III (facility) applications.

During the year, the three major natural gas distributors -- Union Gas Limited, The Consumers' Gas Company Ltd. and Centra Gas Ontario Inc. -- filed 1991 rates applications with the Ontario Energy Board. The distributors sought approval of the gas cost consequences flowing from the gas prices renegotiated with Western Gas Marketing Limited. Each of these distributors either had negotiated new pricing arrangements or had accepted an arbitrated price. The APMC encouraged the Ontario Energy Board to approve the gas cost consequences as submitted because they reflected the results of market-based negotiations in a deregulated environment.

**ALBERTA LEGISLATURE**

**OFFICE OF THE AUDITOR GENERAL**

## AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have audited the balance sheet of the Alberta Petroleum Marketing Commission as at December 31, 1990 and the statement of operations for the Petroleum Marketing Fund and the statement of revenue and expenditure for the Operating Fund for the year then ended. These financial statements are the responsibility of the Commission's management. My responsibility is to express an opinion on these financial statements based on my audit.

I conducted my audit in accordance with generally accepted auditing standards. Those standards require that I plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In my opinion, these financial statements present fairly, in all material respects, the financial position of the Commission as at December 31, 1990 and the results of its operations and the changes in its financial position for the year then ended in accordance with generally accepted accounting principles.

Donald D. Salmon

FCA
Auditor General

Edmonton, Alberta
March 28, 1991

## BALANCE SHEET

| At December 31, | 1990 | 1989 |
|---|---|---|
| **ASSETS** | | |
| **PETROLEUM MARKETING FUND** | | |
| **Current** | | |
| Cash | $ 20,851,894 | $ 23,543,660 |
| Accounts receivable | 193,227,513 | 148,123,140 |
| Inventory held on behalf of the Province of Alberta *(Note 3)* | 128,417,970 | 117,050,170 |
| | 342,497,377 | 288,716,970 |
| **OPERATING FUND** | | |
| **Current** | | |
| Cash | 5,029,812 | 5,347,675 |
| Accounts receivable | 261,195 | 375,162 |
| | 5,291,007 | 5,722,837 |
| **Furniture, equipment and leasehold improvements, at cost *(Note 4)*** | 3,186,830 | 3,029,616 |
| | 8,477,837 | 8,752,453 |
| | $ 350,975,214 | $ 297,469,423 |
| **LIABILITIES** | | |
| **PETROLEUM MARKETING FUND** | | |
| **Current** | | |
| Accounts payable | $ 41,449,987 | $ 52,141,280 |
| Payable to the Province of Alberta *(Note 3)* | | |
| Conventional oil - royalty share | 258,824,871 | 206,810,071 |
| Synthetic oil - equity share | 42,222,519 | 29,765,619 |
| | 342,497,377 | 288,716,970 |
| **OPERATING FUND** | | |
| **Current** | | |
| Accounts payable | 205,575 | 227,944 |
| Payable to the Province of Alberta | 3,264,932 | 3,692,393 |
| Deferred contributions | 1,820,500 | 1,802,500 |
| | 5,291,007 | 5,722,837 |
| **Equity in fixed assets** | 3,186,830 | 3,029,616 |
| | 8,477,837 | 8,752,453 |
| | $ 350,975,214 | $ 297,469,423 |

The accompanying notes are part of these financial statements.

## STATEMENT OF OPERATIONS - PETROLEUM MARKETING FUND

| Year Ended December 31, | 1990 | 1989 |
|---|---|---|
| **Revenue from crude oil sales** | **$ 2,078,197,543** | $1,771,615,517 |
| **Expenditure** | | |
| Crude oil purchases *(Note 5)* | **390,956,825** | 419,372,259 |
| Transportation | **89,422,755** | 93,496,749 |
| | **480,379,580** | 512,869,008 |
| **Excess of revenue over expenditure** | **1,597,817,963** | 1,258,746,509 |
| **Net revenue to the Province of Alberta** | | |
| Conventional oil - royalty share | **1,338,672,268** | 1,060,942,404 |
| Synthetic oil - equity share | **259,145,695** | 197,804,105 |
| | **1,597,817,963** | 1,258,746,509 |
| | **$ -** | $ - |

## STATEMENT OF REVENUE AND EXPENDITURE - OPERATING FUND

| Year Ended December 31, | 1990 | 1989 |
|---|---|---|
| **Revenue** | | |
| Crude oil marketing fees | **$ 2,834,901** | $ 2,973,494 |
| Interest | **1,621,017** | 1,602,615 |
| Natural gas price component service fees | **322,248** | 278,250 |
| | **4,778,166** | 4,854,359 |
| **Expenditure** | | |
| Salaries and benefits | **5,099,132** | 4,868,681 |
| Office rental and maintenance *(Note 6)* | **1,019,469** | 1,040,370 |
| Regulatory hearings *(Note 7)* | **829,685** | 260,494 |
| Office supplies and services | **231,703** | 230,066 |
| Travel | **193,555** | 194,927 |
| Equipment rental and maintenance | **177,694** | 232,918 |
| Furniture, equipment and leasehold improvements | **157,214** | 384,392 |
| Computer services | **114,951** | 155,015 |
| Consulting fees | **77,184** | 149,150 |
| | **7,900,587** | 7,516,013 |
| **Excess of expenditure over revenue** | **3,122,421** | 2,661,654 |
| **Net contribution from the Province of Alberta** *(Note 8)* | **3,122,421** | 2,661,654 |
| | **$ -** | $ - |

# NOTES TO THE FINANCIAL STATEMENTS

December 31, 1990

## NOTE 1 AUTHORITY

The Alberta Petroleum Marketing Commission operates under the authority of the Petroleum Marketing Act, Chapter P-5, Revised Statutes of Alberta 1980, as amended, and the Natural Gas Marketing Act, Chapter N-2.8, Statutes of Alberta 1986, as amended.

## NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

### General

These financial statements have been prepared in accordance with generally accepted accounting principles, except that purchases of furniture, equipment and leasehold improvements are charged to operating fund expenditure, net of disposal proceeds, in the year of acquisition. The balance sheet, however, states the cumulative amount of such expenditures in respect of all fixed assets presently owned with the offsetting credit to equity in fixed assets.

### Inventory Held on Behalf of the Province of Alberta

Inventory held on behalf of the Province, representing Alberta's share of royalty and synthetic oil in feeder and trunk pipelines, is stated at actual net realizable value.

### Foreign Currency Translation

Assets and liabilities denominated in foreign currency are translated into Canadian dollars at forward exchange contract rates or, where not covered by forward exchange contracts, at the rate of exchange in effect at the balance sheet date. Revenue and expenditures are translated at forward exchange contract rates or, where not covered by forward exchange contracts, at average monthly exchange rates.

### Deferred Contributions

Contributions received from the Province of Alberta to cover operating costs for the three month period subsequent to the fiscal year end have been deferred. Contributions by the Province are based on a yearly budget for the period April 1 to March 31.

### Operating Fund Expenditure

The Take-or-pay Costs Sharing Fund is administered pursuant to the Take-or-pay Costs Sharing Act. The expenditure related to the administration of this Fund is reflected in the Statement of Revenue and Expenditure - Operating Fund.

### Changes in Financial Position

A statement of changes in financial position is not provided as disclosure in these financial statements is considered adequate.

## NOTE 3 CHANGE IN ACCOUNTING POLICY

Inventory held on behalf of the Province, representing Alberta's share of royalty and synthetic oil in feeder and trunk pipelines, is now reported as an asset of the Fund in order to reflect the Commission's control of the oil. The effect of this change is to increase Payable to the Province of Alberta for the current year by amounts of $119,205,529 for conventional oil and $9,212,441 for synthetic oil. Similar increases for 1989 were, respectively, $106,109,028 and $10,941,142. The change has no effect on the Statement of Operations - Petroleum Marketing Fund.

## NOTE 4 FURNITURE, EQUIPMENT AND LEASEHOLD IMPROVEMENTS

During 1990, changes in furniture, equipment and leasehold improvements were as follows:

| | Opening Balance | Additions | Disposals | Closing Balance |
|---|---|---|---|---|
| Furniture and equipment | $ 2,187,149 | $ 157,214 | $ - | $ 2,344,363 |
| Leasehold improvements | 842,467 | - | - | 842,467 |
| | $ 3,029,616 | $ 157,214 | $ - | $ 3,186,830 |

## NOTE 5 PETROLEUM MARKETING OPERATIONS

**Agency Relationships and Marketing Services**

Under the Petroleum Marketing Act, the Commission is designated agent of the Province of Alberta to accept delivery of, and market the Crown's royalty share of crude oil. Through an agreement dated August 4, 1977, the Commission is also designated agent of the Province to market its 16.74 percent equity share of production from the Syncrude Canada project. In addition, the Commission offers marketing services to Alberta producers.

**Crude Oil Purchase/Sale Exchange Agreements**

In order to assist in meeting its sales obligations, the Commission enters into crude oil exchange agreements. Sales and purchases under these agreements are included in revenue and crude oil purchases. In 1990, these purchases amounted to $232,099,770 (1989 $234,763,221).

## NOTE 6 COMMITMENT

Effective December 1, 1981, the Commission signed a fifteen year lease for office accommodation at a minimum annual rental of $692,360 plus other occupancy costs.

## NOTE 7 REGULATORY HEARINGS

| Regulatory hearing costs are comprised of the following: | 1990 | 1989 |
|---|---|---|
| Outside counsel and consultants | $ 671,513 | $ 161,644 |
| Travel | 110,909 | 56,430 |
| Transcripts | 47,263 | 42,420 |
| | $ 829,685 | $ 260,494 |

## NOTE 8 NET CONTRIBUTION FROM THE PROVINCE OF ALBERTA

The Commission operates under a grant from the Province, based on its budget year of April 1 to March 31. For the 1990-91 budget year this amounted to $7,282,000 (1989-90 $7,210,000). Revenues from crude oil marketing fees, interest and natural gas price component service fees are used to reduce the operating grant requirement and any surplus is subsequently returned to the Province. During the year this surplus amounted to $4,569,040 (1989 $4,696,720).

## NOTE 9 COMPARATIVE FIGURES

The 1989 figures have been reclassified where necessary to conform to the 1990 presentation.

## NOTE 10 APPROVAL OF FINANCIAL STATEMENTS

These financial statements were approved by the Commission.

**ALBERTA LEGISLATURE**

**OFFICE OF THE AUDITOR GENERAL**

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have audited the balance sheet of the Take-or-pay Costs Sharing Fund as at December 31, 1990 and the statement of revenue and expenditure for the year then ended. These financial statements are the responsibility of the Commission's management. My responsibility is to express an opinion on these financial statements based on my audit.

I conducted my audit in accordance with generally accepted auditing standards. Those standards require that I plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In my opinion, these financial statements present fairly, in all material respects, the financial position of the Fund as at December 31, 1990 and the results of its operations and the changes in its financial position for the year then ended in accordance with the disclosed basis of accounting as described in Note 2 to the financial statements.

Donald D. Salmon

FCA
Auditor General

Edmonton, Alberta
March 28, 1991

## TAKE-OR-PAY COSTS SHARING FUND

### BALANCE SHEET

| At December 31, | 1990 | 1989 |
|---|---|---|
| **ASSETS** | | |
| **Current** | | |
| Cash | $ 3,319,339 | $ 2,042,157 |
| Accounts receivable | 10,684,487 | 14,971,550 |
| | $ 14,003,826 | $ 17,013,707 |
| **LIABILITIES** | | |
| **Current** | | |
| Accounts payable | $ 4,080,112 | $ 5,750,226 |
| Deferred revenue *(Note 3)* | 9,923,714 | 11,263,481 |
| | $ 14,003,826 | $ 17,013,707 |

### STATEMENT OF REVENUE AND EXPENDITURE

| Year ended December 31, | 1990 | 1989 |
|---|---|---|
| **Revenue** | | |
| Take-or-pay levies | $ 139,459,972 | $ 184,615,761 |
| Interest | 328,212 | 266,755 |
| | 139,788,184 | 184,882,516 |
| **Expenditure** | | |
| Take-or-pay costs | 139,788,184 | 184,882,516 |
| **Excess of revenue over expenditure** | $ - | $ - |

The accompanying notes are part of these financial statements.

## NOTES TO THE FINANCIAL STATEMENTS

December 31, 1990

### NOTE 1 AUTHORITY

The Take-or-pay Costs Sharing Fund was established by the Take-or-pay Costs Sharing Act, Chapter T-0.1, Statutes of Alberta 1986, as amended.

### NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

**Administration Costs**

In accordance with the Take-or-pay Costs Sharing Act, the Fund is administered by the Alberta Petroleum Marketing Commission. Costs of administration are reflected in the Statement of Revenue and Expenditure - Operating Fund.

**Changes in Financial Position**

A statement of changes in financial position is not provided as disclosure in these financial statements is considered adequate.

### NOTE 3 DEFERRED REVENUE

Deferred revenue represents the portion of current year revenue which will be used to pay future Take-or-pay costs.

### NOTE 4 APPROVAL OF FINANCIAL STATEMENTS

These financial statements were approved by the Commission.

# DIRECTORY

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As at date of publication

Printed in Canada